Life Cycle Greenhouse Gas Emissions From U.S. Liquefied Natural Gas Exports: Implications for End Uses

Supporting Information

Leslie Abrahams[1,2]*, Constantine Samaras[2], W. Michael Griffin[1], H. Scott Matthews[1,2]

[1]Department of Engineering and Public Policy, and [2]Civil and Environmental Engineering Department, Carnegie Mellon University, Pittsburgh, PA 15213
*labrahams@cmu.edu
+001 412 2682670

Table of Contents

1. Conversion Factors

Table S1: Conversion factors used in this study

1	HP	=	0.746	kw
1	m^3	=	35.3	ft^3
1	ft^3 LNG	=	0.2931	kWh
1	m^3 LNG	=	21,189	ft^3 NG
1	Mcf NG	=	127	kWh
1	kWh	=	3.6	MJ
1	metric ton	=	1,000,000	g
1	ft^3 NG	=	1.06	MJ
1	lb	=	453.59	g
1	MMBtu	=	1,055	MJ

2. Upstream GHG Emissions

The Monte Carlo simulation inputs for the production stage of the LNG life cycle (Table S.2) were adapted from Weber 2012[1]. The units are g CO_2-equiv/MJ unless otherwise noted.

Table S2: Production and transportation emissions parameters for upstream emissions simulation

	min	**most likely**	**max**
Well pad construction	0.05	0.13	0.3
Well drilling	0.1	0.2	0.4
Fracturing water management	0.04	0.23	0.5
Fracturing chemicals	0.04	0.07	0.1
Conv well completion	0.01	0.12	0.41
Unconv well completion: total vent/flare (mt CH4)	13.5	177	385
Well completion: flare rate (fraction)	0.15	0.41	1
Well completion: EUR (Bcf)	0.5	2	5.3
Flaring	0	0.43	1.3
Unconv Lease/Plant energy	2	3.3	4.1
Conv. Lease plant energy	2	3.3	4.3
CO_2 vent	0.2	0.7	2.8
Compression fuel	0.2	0.38	0.6
Leak percent[2]	2	3	4

The distributions from Table S2 were then used to calculate upstream emissions from both conventional and unconventional natural gas development (Table S3). These two estimates were then weighted by the percentage of their contribution to total natural gas development as projected by the Energy Information Association (EIA) in their Annual Energy Outlook.

Table S3: Calculations of upstream emissions

Parameter	Type	Unit	Value (min, avg, max)		
Energy input	Assumed parameter	MJ		1	
percent methane by volume	Triangular (min, avg, max)	%	0.83	0.93	0.95
Fugitive Emissions	Calculated (5th, avg, 95th)	g CO2-e/MJ	11.9	20.7	30.72
unconventional emissions	Calculated (5th, avg, 95th)	g CO2-e/MJ	18	27	37
conventional emissions	Calculated (5th, avg, 95th)	g CO2-e/MJ	19	28.5	39.5
% of gas mix from shale	Assumed parameter	%		0.4	
Total Upstream Emissions	Calculated (5th, avg, 95th)	g CO2-e/MJ	18.5	27.9	28.4

The upstream model of the natural gas life ccle (extraction, production, and pipeline transmission) was validated by comparing this model's emissions estimates to the harmonized emissions estimates reported by Heath et al. (2014).[3] To obtain upstream estimates from the harmonized life cycle emissions reported by Heath et al., the harmonized combustion emissions (360 g CO_2-equiv/kWh) were subtracted from the total life cycle emissions. The resulting values were then converted to MJ and multiplied by the harmonized efficiency (51%) to obtain the emissions on a heat input basis (g CO_2-equiv/MJ extracted). Finally, a weighted average of shale and conventional estimates was calculated using the assumption that 40% of the natural gas extracted in the U.S. is unconventional (Table S16).

These harmonized upstream estimates adapted from Heath et al. are all based on the AR4 GWP value for methane of 25. Therefore, the normal distribution in this model used to represent the methane GWP was replaced with the AR4 point estimate. The harmonized upstream estimates, however, still maintain unique assumptions of the fugitive emissions rate. To validate this model, each leakage rate from the harmonized studies was inputted into our model. The results of the simulation with that leakage rate is reported in Table S16 (mean and 90% confidence interval).

We find that this model, when compared to the harmonized upstream emissions using the AR4 GWP and the unique fugitive emissions estimates from each study, results in four of the harmonized estimates being within the 90% confidence interval. The model over estimates four of the studies, and underestimates one study.

Table S4: A comparison of harmonized upstream emissions estimates (adapted from Heath et al. 2014) to the results from our model with the AR4 GWP and the reported leakage rate of each study as model inputs.

	Harmonized Life Cycle Emissions[3]		**harmonized upstream***	**leakage rate**	**Results from this study's model ($g\ CO_2$-e/MJ)**		
study	Shale	Conventional	($g\ CO_2$-e/MJ)	%	mean	5%	95%
Howarth[4]	746	647	46.3	2.8	20.3	18.8	22
Howarth[4]	567	473	21.3	6.2	36.6	34.5	38.5
Jiang[5]**/Venkatesh**[6]	497	439	14.5	2.2	17.5	16	19
Skone[7]	438	439	11.1	3.9	25.6	23.8	27.4
Hultman[8]	438	438	11.1	2.8	20.3	18.8	22
Burnham[9]	517	557	25.6	2	16.5	15.1	18
Stephenson[10]	434	420	9.3	0.66	10	8.7	11.6
Heath[11]**/ O'Donoughue**[12]	459	450	13.3	1.3	13	11.8	14.8
Laurenzi[13]	470	450	13.9	1.4	13.6	12.2	15.2
This study	-	-	-	triang(2,3,4)	21.3	17.6	24.8

* Adapted from Heath et al. (2014)

3. Liquefaction GHG Emissions

To estimate emissions from the liquefaction stage of the LNG life cycle, estimates were compiled from several studies (Table S4). These estimates were then used to fit a distribution representing the range of possible emissions.

The GWP used to estimate the liquefaction and regasification emissions is the exception to the use of the AR5 distribution to quantify upstream and shipping CO_2–equivalent emissions. In the literature, these estimates have generally been reported as aggregate CO_2-equivalent values based on AR3, AR4, or AR5 GWPs, rather than as disaggregated CO_2 and CH_4 emissions. Therefore the emissions cannot readily be adjusted based on the AR5 GWP distribution. Since the GWP has increased in AR5, the use of earlier GWP in the liquefaction and regasification stages of the LCA imply that the results presented in this study are likely lower bound estimates. This is especially true with respect to the 20-year GWP results, which have 100-year GWP embedded in the liquefaction and regasification estimates. However, because the majority of emissions from liquefaction and regasifaction stages derive from fuel combustion for energy rather than from methane leakage or venting,[14] it is likely that these estimates would only nominally increase based on the AR5 adjustment of the methane 100-year or 20-year GWP. To test this assumption, the ratio of methane vented per MJ of natural gas during the liquefaction stage suggested by Tamura et al. (2001)[14] (.026 g/MJ) was applied to each of the other study estimates to adjust them to the AR5 GWP distribution. This did not change the overall life cycle emissions.

Table S5: Collected estimates from various studies on liquefaction stage emissions

Source	Estimate (g-CO2-e/MJ)
Hardisty 2012[15]	8.06
Artecini 2010[16]	6.51
Skone 2012[7]	7.62
Skone 2014[17]	8.24
Heede 2006[18]	6.15
Verbeek 2011[19]	5.90
LCFS[20]	7.30
Cohen 2013[21]	3.69
Biswas 2011[22]	7.70
Yoon 1999[23]	8.76
Okamura 2007[24]	8.36
Tamura 2001[14]	7.52
Yost 2003 [25]	3.83
Barnett 2012 [26]	2.41
Barnett 2012 [26]	5.17
Barnett 2012 [26]	3.76
Barnett 2012 [26]	3.97
Barnett 2012 [26]	3.97
Barnett 2012 [26]	3.43
Barnett 2012 [26]	6.76
Barnett 2012 [26]	8.05
Barnett 2012 [26]	3.76
Barnett 2012 [26]	5.87
Barnett 2012 [26]	4.19
Barnett 2012 [26]	4.89

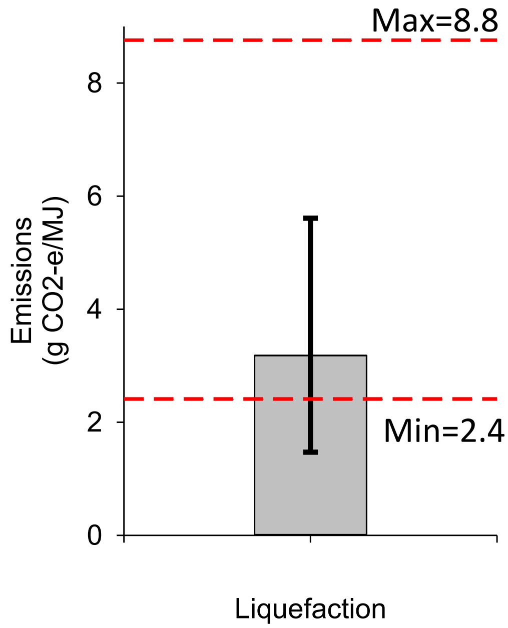


Figure S1: Liquefaction stage estimates using the distribution fit to the liquefaction stage estimates versus the maximum and minimum liquefaction stage estimates found in the literature

The distribution derived from using the emissions estimates found in the literature and industry reports mostly lies between the maximum and minimum estimates, but primarily captures the lower values in the range. Because technology is becoming more efficient, it is likely that the emissions range of future liquefaction plants will fall within the uncertainty captured by the constructed distribution. Therefore, this distribution was used to represent the liquefaction stage GHG emissions in this study.

4. Shipping emissions

Liquefied natural gas is typically shipped on specialized LNG tankers, powered by either regasified cargo LNG or diesel. The results of the simulation indicate that the fuel source for the tanker does not greatly impact the greenhouse gas emissions on a per unit basis. LNG tankers powered by both steam and diesel result in approximately the same contribution to life cycle emissions when shipping distance and cargo capacity are held constant. Tanker capacity, rather than shipping distance or fuel type, is the most significant factor in determining shipping GHG emissions (see manuscript Figure 1A). The 140,000 m^3 capacity tanker can result in shipping emissions as much as double the emissions from the 260,000 m^3 capacity tanker. The emissions reductions achieved by using large capacity tankers are most apparent for longer transport distances (such as from MD to Asia). Typically, exporters are driven to use these large capacity tankers for long distance shipping due to economic considerations. Smaller capacity tankers are instead used for shorter transport distances such as Cove Point to Europe. As a result, although shipping from MD to Europe always results in fewer emissions than shipping to Asia, the emissions from MD to both Europe and Asia are in the same approximate range (1-3 g CO_2-equiv/MJ) despite the differences in transport distance.

If the origin and destination of the LNG were to have a significant impact on life cycle emissions, it would be important for the DOE to consider the location of the terminal requesting a permit as well as the expected shipping destinations from that LNG facility. To quantify these impacts, this study simulated shipping emissions from three approved facilities in the U.S. to six importing countries in Europe and Asia assuming a large capacity tanker. This was then compared to the results from shipping using a distribution of all eighteen shipping distances.

An analysis of the impact of origin and destination on shipping and landed (pre-combustion) life cycle emissions is described in SI sections 4 and 5. When individual origins and/or destinations were not being considered, the distribution capturing all eighteen potential shipping distances was used in simulating life cycle emissions. As shown in Figure 2B, the 90% confidence interval of this distribution captures the uncertainty associated with the various shipping origins and destinations. Our estimate of the mean landed life cycle GHGs for exported U.S. LNG after regasification at the importing country is 37 g CO_2-equiv/MJ with a range of 27 to 50 (Figure S2). The average shipping emissions and 90% confidence intervals from each port of origin to each importing country can be found in SI (Table S9).

The shipping distances from the three U.S. ports to the six different destinations used in this study were found using an online port distance calculator (Table S5). These distances were then used to determine a distribution representing the possible range in shipping distances (Table S6). Then, the shipping emissions were calculated using the parameters and assumptions in Table S7. The resulting shipping emissions are shown in Table S8.

Table S6: Shipping distances as determined by the shortest (most efficient) trade route from origin to destination

Shipping distances[27] (nm)	**Japan**	**Korea**	**India**	**China**	**UK**	**Netherlands**
from/to	*Osaka*	*Incheon*	*Mumbai*	*Shanghai*	*South hook*	*Rotterdam*
Cove Point, MD	9,914	10,431	8,444	10,514	3,279	3,670
Coos Bay, OR	4,584	5,114	9,560	5,483	8,091	8,463
Sabine Pass, LA	9,481	9,998	9,649	10,081	4,588	4,974

Table S7: The parameters of the distribution fit to shipping distances used as input to the simulation. The units are in nautical miles (nm).

Distribution	***Min***	***Most likely***	***Max***
Triangular	1,890	10,514	10,514

Table S8: Assumptions, parameters, and calculations used to estimate shipping emissions

Tanker Cargo Capacity (m^3 LNG)	260,000		
Tanker Cargo Capacity (MJ NG)	5,839,688,400		
Speed (knots)[18]	19.5		
Natural BOG (%/day)	0.125		
LNG boil off (m^3/day)	325		
BOG NG equivalent (m^3/day)	195,002		
BOG power (MW/day)	1,997		
Distance (nm)	7,640		
Number of hours of Journey (1 way)	392		
Number of days of Journey (1 way)	16		
Total BOG	32,600		
Power (HP)[26]	40,000		
Power (MW)	30		
Number of engines	1		
Engine Type	STEAM	DIESEL	
Engine Efficiency	30%	50%	
MW input/hour	99	60	
Total MW input (full load)	38,953	23,372	
Engine Mode[28]	**Trip (%)**	**Load factor (%)**	
idle	1%	2%	
maneuvering	2%	8%	
precautionary zone operations	5%	12%	
slow cruise	7%	50%	
full cruise	85%	95%	
	STEAM	DIESEL	
percent of full load	0.9	0.9	
Total MW input	33116	19869	
Total MJ input	119,216,639	71,529,983	
	ALL BOG	ALL DIESEL	
natural BOG (MW)	32,600	32,600	
regassified/reliquefied (MW)	516	32,600	
% combusted to regassify/reliquify	3%	8%	* assumes NG is used in both cases
non propulsion combusted (MW)	15	2,608	
non propulsion combusted (MJ)	55,707	9,388,778	

return trip (MJ)	71,529,983	71,529,983	*assumes diesel in both cases
days at port[26]	3	3	
Engine Mode (diesel)	idle	idle	
port full load (MW)	4,295	4,295	
port at idle (MW)	86	86	
port at idle (MJ)	309,257	309,257	
Emission Factor (NG/diesel) g CO_2-equiv/MJ	48	72	
TOTAL EMISSIONS (g CO_2-e)	10,822,903,123	10,699,501,174	
Shipping Emissions (g CO_2-equiv/MJ)	1.9	1.8	

Table S9: Estimated shipping emissions by origin and destination (100-yr GWP)

From/To		**Japan**			**Korea**			**India**	
gCO_2-e/MJ	***mean***	***5%***	***95%***	***mean***	***5%***	***95%***	***mean***	***5%***	***95%***
MD	2.5	*2.3*	*2.8*	2.6	*2.4*	*2.9*	2.1	*1.9*	*2.4*
OR	1.2	*1.1*	*1.3*	1.3	*1.2*	*1.4*	2.4	*2.2*	*2.7*
LA	2.4	*2.2*	*2.6*	2.5	*2.3*	*2.8*	2.4	*2.2*	*2.7*

From/To		**China**			**UK**			**The Netherlands**	
gCO_2-e/MJ	***mean***	***5%***	***95%***	***mean***	***5%***	***95%***	***mean***	***5%***	***95%***
MD	2.7	*2.4*	*2.9*	0.8	*0.8*	*0.9*	0.9	*0.8*	*1*
OR	1.4	*1.3*	*1.5*	2.1	*1.9*	*2.2*	2.1	*2*	*2.4*
LA	2.6	*2.3*	*2.8*	1.2	*1.1*	*1.3*	1.3	*1.2*	*1.4*

As expected, for a given tanker capacity, the shorter the transport distance the fewer GHGs are emitted. This indicates that there is an opportunity to reduce emissions by strategically coordinating export origin and importing destination. For example, if LNG were to be shipped to China from Oregon instead of from Maryland, there would be a savings of about 1 g CO_2-e/MJ. While this is only about 2.7% of the total pre-combustion (landed) LNG export emissions (See SI Section 5), if the U.S. were to supply China with 0.3 Tcf of natural gas (a fifth of its total 2011 imports) this shipping strategy would result in an annual emissions savings of 140,000 metric tons of CO_2-e per year.

5. Landed life cycle emissions

The simulation results for the landed (pre-combustion) emissions are shown in Figure S3. The majority of the uncertainty lies in the upstream component of the natural gas life cycle, and is most sensitive to the fugitive emissions rate. Liquefaction, shipping, and regasification emissions account for 17%, 5%, and 2% of the total landed emissions respectively. The landed life cycle emissions for each origin and destination are reported in Table S9.

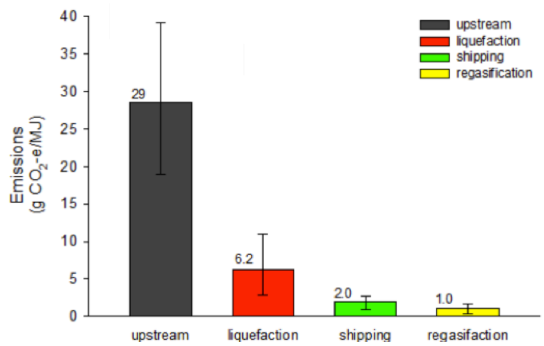


Figure S2: Landed (pre-combustion) life cycle emissions from US LNG exports

Table S10: Landed emissions (production, liquefaction, shipping, regasification) at each importing country

From/To		**Japan**			**Korea**			**India**	
gCO₂-e/MJ	***mean***	***5%***	***95%***	***mean***	***5%***	***95%***	***mean***	***5%***	***95%***
MD	39	*25*	*54*	39	*25*	*55*	38	*24*	*54*
OR	37	*23*	*53*	38	*23*	*53*	39	*24*	*54*
LA	39	*24*	*54*	39	*25*	*54*	39	*24*	*54*

From/To		**China**			**UK**			**The Netherlands**	
gCO₂-e/MJ	***mean***	***5%***	***95%***	***mean***	***5%***	***95%***	***mean***	***5%***	***95%***
MD	39	*25*	*55*	37	*23*	*53*	37	*23*	*53*
OR	38	*24*	*53*	38	*24*	*54*	38	*24*	*54*
LA	39	*25*	*54*	37	*23*	*53*	38	*23*	*53*

6. Electricity generation

The emissions from electricity generation were calculated based on the parameters and assumptions outlined in Table S9 and S10. The resulting life cycle emissions for electricity generation from U.S. LNG, Russian natural gas, and coal using both a 100-year and 20-year GWP are shown in Table S11.

Table S11: Parameters and assumptions used to estimate emissions from electricity generation from NGCC power plant

NGCC Power plant efficiency (min, most, max)	0.41	0.46	0.51
Emissions factor (min, max)[3] gCO_2-equiv/MJ	43	50	

Table S125: Parameters for the distributions used to represent upstream coal emissions (adapted from Venkatesh et al. 2012)[29] and coal fired power plant emissions (adapted from Steinmann et al. 2014)[30]

Coal production (g CO_2/MJ) triang(min,avg,max)	.4	.6	.7
Coal producgion – methane (CH_4/MJ)	.02	.15	.5
Coal transport (g CO_2/MJ)	.2	1.3	3.2
Coal Power Plant Emissions (kg/kWh)	log-logistic	mean = 1.09	std dev = .203

Table S6: Life cycle emissions estimate results for LNG exports, Russian natural gas, and coal

100-yr GWP			
	mean	*5%*	*95%*
LNG EXPORTS		g CO_2-e/kWh	
upstream	223	147	308
liquefaction	49	22	86
shipping	15	8	21
regasification	8	2	13
combustion	364	328	403
total	655	562	770
RUSSIAN NG:			
upstream	389	251	533
combustion	364	328	403
total	752	604	905
COAL:			
upstream	117	52	210
combustion	1085	918	1378
total	1,200	1013	1,506

20-yr GWP

	mean	*5%*	*95%*
LNG EXPORTS		g CO_2-e/kWh	
upstream	469	323	638
liquefaction	49	22	86
shipping	15	8	21
regasification	8	2	13
combustion	364	328	403
total	900	738	1,091
RUSSIAN NG:			
upstream	871	606	1,152
combustion	364	328	403
total	1,231	961	1,519
COAL:			
upstream	248	94	445
combustion	1,085	918	1,378
total	1,332	1084	1,677

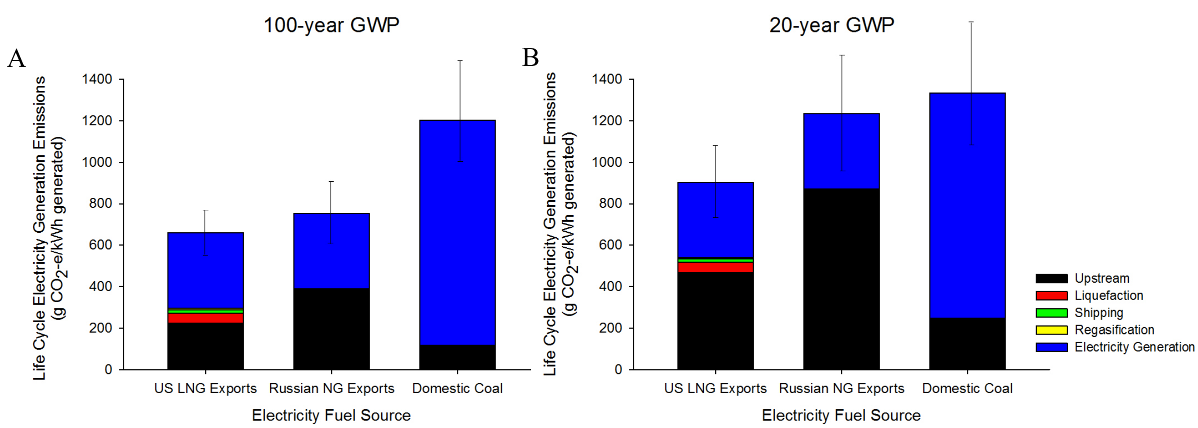
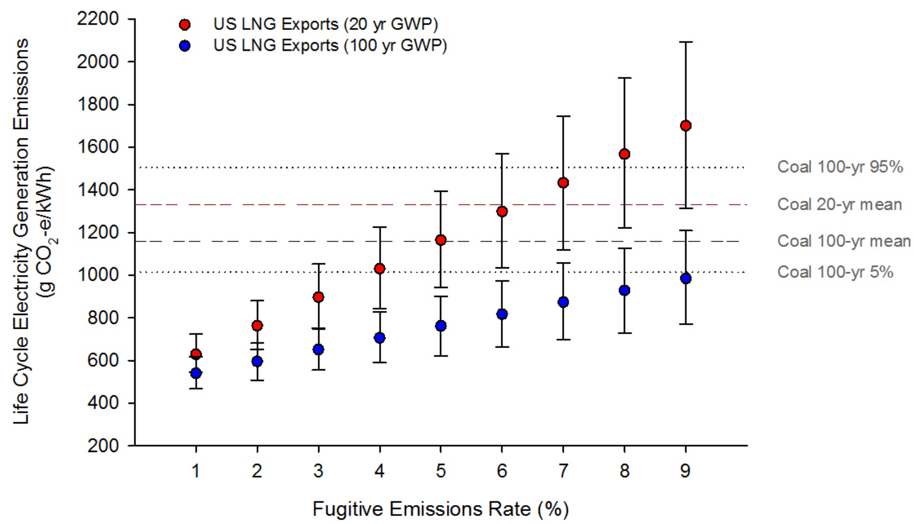


Figure S3: Comparison of life cycle greenhouse gas emissions from alternative fuel sources including U.S. LNG exports, Russian natural gas exports via pipeline, and coal for electricity generation

The sensitivity of the above results to the fugitive emissions rate assumption was tested. The results are shown in Figure S4 and S5. For the 100-yr GWP, natural gas results in fewer emissions than coal over a 9% methane leakage rate. However, for the 20-yr GWP, the break-even point is around a 6% fugitive emissions rate (Figure S4A). Greenhouse gas emissions from U.S. LNG exports will always remain below Russian natural gas exports, as long as the domestic fugitive emissions rate is below the assumed Russian fugitive emissions rate (Figure S4B).

A



B

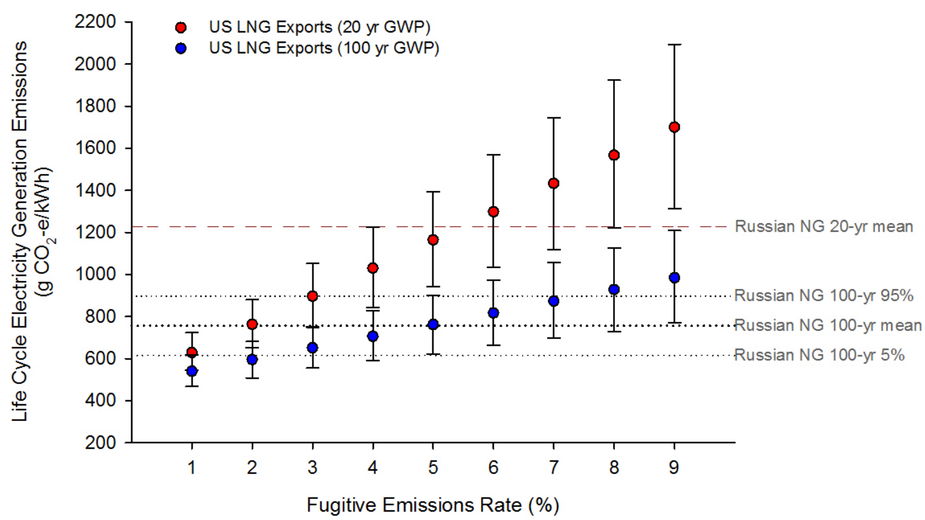


Figure S4: The sensitivity of life cycle emissions of LNG exports for electricity generation to fugitive emissions rates for 100-yr and 20-yr GWPs compared to A) average emissions from coal electricity generation, and B) average emissions from Russian natural gas electricity generation.

For consistency with the DOE's analysis,[17] this analysis uses a similar assumption that the natural gas exported both from the U.S. and from Russia is used at or near the import destination. Therefore, no further emissions from pipeline transmission after regasification were included in these life cycle estimates. Because of the distribution of percentage-based leakage rates used in this analysis, further emissions in the importing country could be implicitly represented inside of the existing range. If instead the natural gas was assumed to be widely distributed after regasification resulting in additional leakage, life cycle emissions would increase and the break-even upstream fugitive emissions rate for the U.S. would decrease. For example, if LNG arriving at the regasification facility at Rotterdam in The Netherlands was widely distributed across the European Union (EU), without any specific data on European pipeline leakage rates, the 2-4% range used for the U.S. could be applied to represent both the potential variability in transport distance within the EU and the uncertainty in the fugitive emissions rate. In this sensitivity case, the net savings from displacing coal for electricity generation are reduced from 550 g CO_2-equiv/kWh to about 375 g CO_2-equiv/kWh for a 100-year GWP (Figure S5A). The break-even domestic fugitive emissions rate drops to 9% on a 100-year GWP and 3% on a 20-year GWP (Figure S5B).

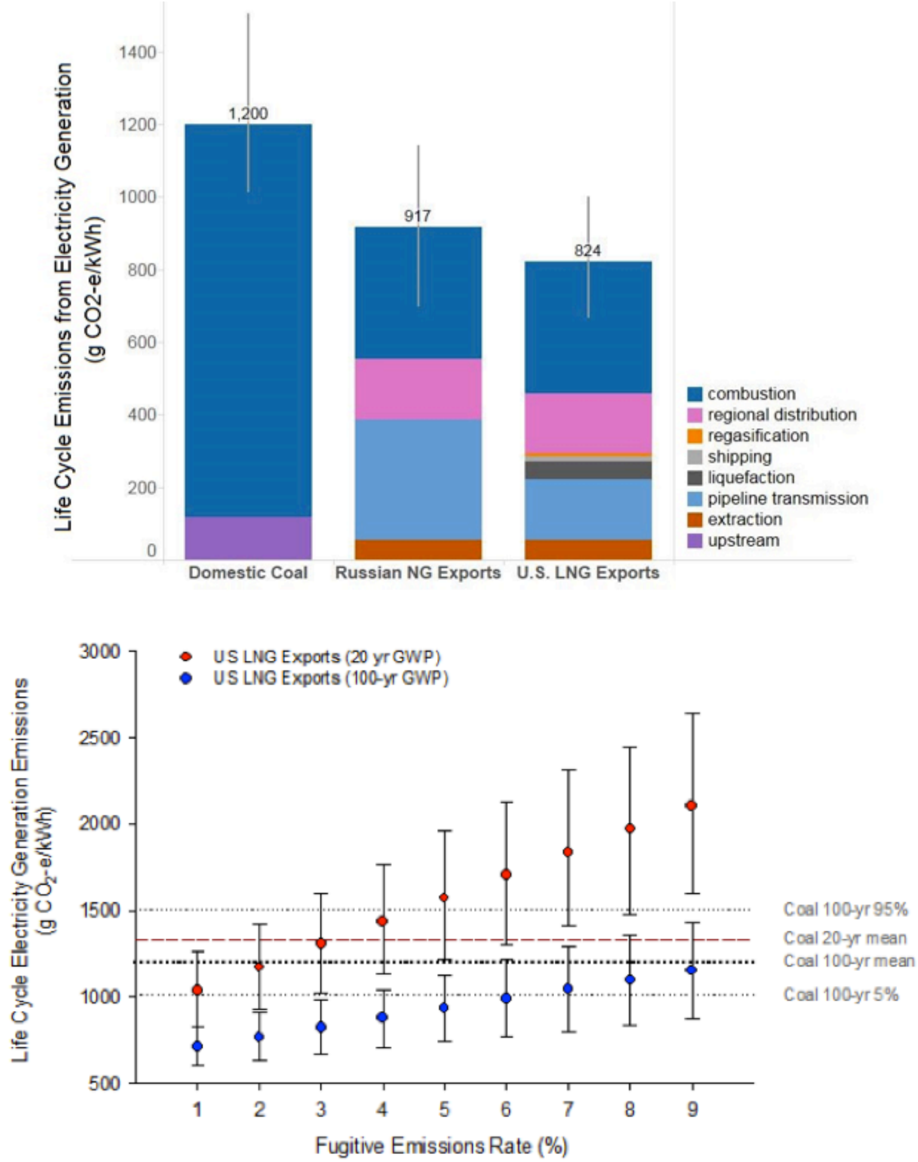


Figure S5: Assuming post-regasification pipeline distribution of 2-4%, A) a comparison of emissions from alternative fuel sources for a 100-yr GWP, and B) a sensitivity analysis of the domestic upstream fugitive emissions rate as compared to average coal life cycle emissions for electricity generation

7. Industrial Heating

The assumptions and parameters used to calculate emissions from industrial heating are outlined in Table S12. The results are shown in Table S13.

Table S14: Life cycle emissions estimates of LNG exports, Russian natural gas, and coal for industrial heating

Industrial heating efficiency (NG) (min, avg, max)	0.7	0.8	0.94
Combustion emissions factor (NG) [min,max] g/MJ	43.0		50.0
Industrial heating efficiency (Coal) (min, avg, max)	0.75	0.85	0.89
Combustion emissions factor (Coal) (min, avg, max) g/MJ	88	91	98

Table S7: Life cycle emissions for industrial heating using U.S. LNG, Russian natural gas, and coal

100-yr GWP	*mean*	*5%*	*95%*
LNG EXPORTS		g CO_2-e/MJ	
upstream	35	23	49
liquefaction	8	4	14
shipping	2	1	3
regasification	1	0	2
combustion	57	51	65
total	104	87	123
RUSSIAN NG:			
upstream	61	50	85
combustion	57	50	65
total	119	94	145
COAL:			
Upstream	12.2	5.4	22
combustion	111	105	129
total	124	113	137

20-yr GWP

	mean	5%	95%
LNG EXPORTS		g CO_2-e/MJ	
upstream	74	50	102
liquefaction	8	4	14
shipping	2	1	3
regasification	1	0	2
combustion	57	51	65
total	143	115	174
RUSSIAN NG:			
upstream	137	96	183
combustion	57	50	65
total	195	151	243
COAL:			
upstream	26	9.8	49
combustion	111	105	120
total	137	118	161

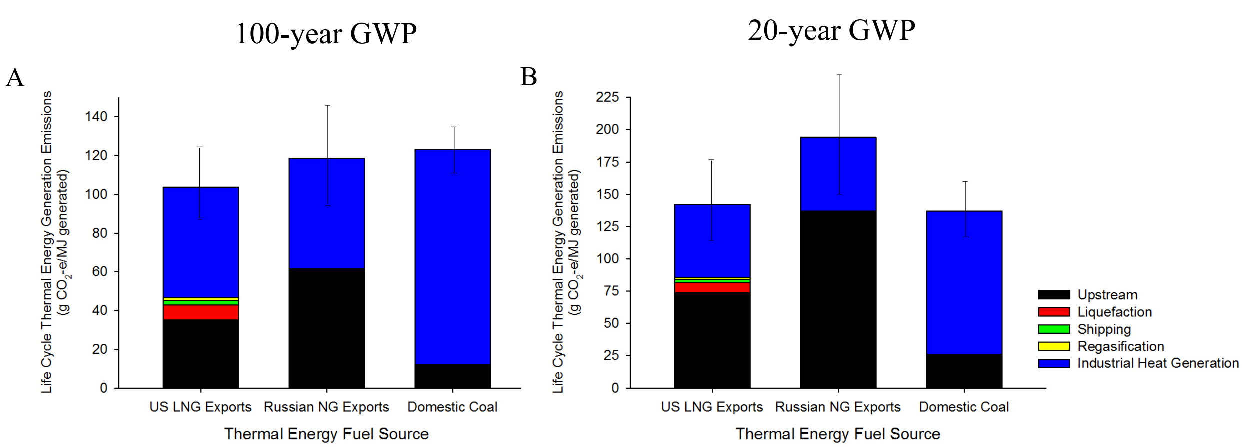
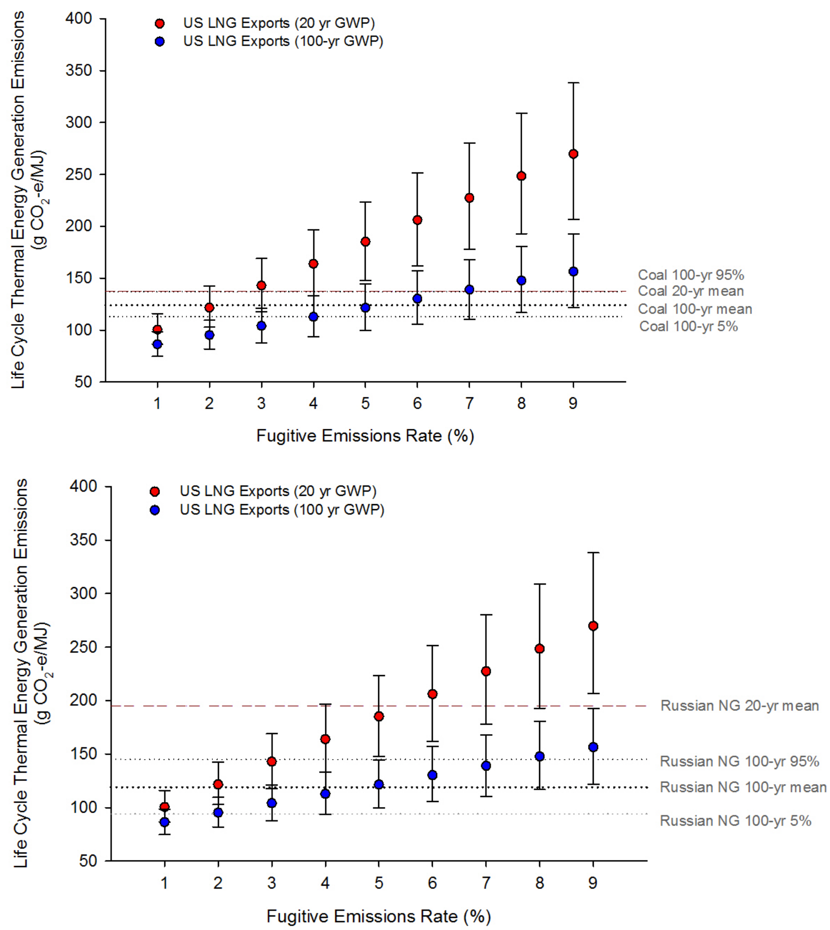


Figure S6: Comparison of life cycle emissions from LNG exports, Russian gas, and coal for industrial heating with A) a 100-year GWP and B) a 20-year GWP

A break-even analysis was conducted to determine the sensitivity of the results to the fugitive emission rate assumption. For the 100-yr GWP, natural gas results in fewer emissions than coal up to 5% methane leakage rate. Using a 20-yr GWP, the break-even point is round a 3% fugitive emissions rate (Figure 7A). Greenhouse gas emissions from U.S. LNG exports will always remain below Russian natural gas exports, as long as the domestic fugitive emissions rate is below the assumed Russian fugitive emissions rate (Figure S7B).

Figure S7: The sensitivity of life cycle emissions of LNG exports for electricity generation to fugitive emissions rates for 100-



yr and 20-yr GWPs compared to A) average emissions from coal electricity generation, and B) average emissions from Russian natural gas electricity generation.

As is described in Section 6, when accounting for wide distribution of the LNG after it is regasified, life cycle emissions would increase and the break-even upstream fugitive emissions rate for the U.S. would decrease. When the LNG is widely distributed after regasification and then used for heating, mean life cycle LNG emissions increase to 130 g CO_2-equiv/MJ, thereby causing a net increase of 6 g CO_2-equiv/MJ over coal use (Figure S8A). The break-even U.S. upstream fugitive emissions rate decreases to 2% for a 100-yr GWP, and U.S. LNG exports would never save GHG emissions over coal using a 20-yr GWP regardless of upstream fugitive emissions rates (Figure S8B).

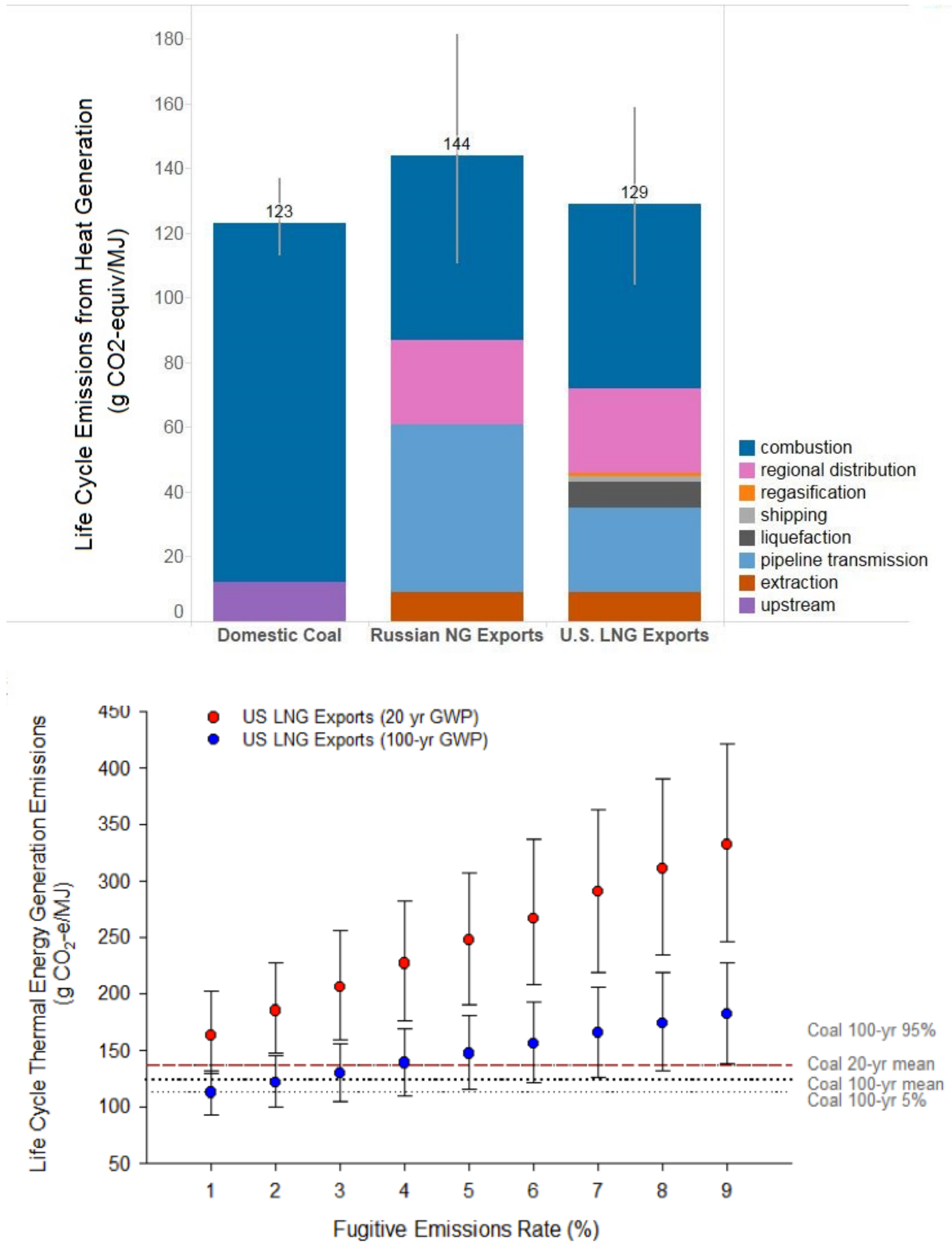


Figure S8: Assuming post-regasification pipeline distribution of 2-4%, A) a comparison of emissions from alternative fuel sources for a 100-yr GWP, and B) a sensitivity analysis of the domestic upstream fugitive emissions rate as compared to average coal life cycle emissions for electricity generation

8. Summary of uncertainty parameters for electricity generation from LNG

Table S8: Summary of uncertainty parameters ranked by their Spearman correlation coefficient. Each parameters distribution and associated units are also shown. Attributions for the parameter distributions are provided in the previous SI sections where the parameters are first presented.

Rank	Name	Units	Description	Spearman Correlation Coefficient
#1	CH_4 100-year GWP		Normal(36,8.5)	0.73
#2	Fugitive Emissions Rate	%	Triangular(2,3,4)	0.40
#3	Liquefaction Emissions	g CO_2-e/MJ	Extreme value(5.1,2.0)	0.35
#4	NGCC Power Plant Efficiency	%	Triangular(.41,.46,.51)	(0.20)
#5	Natural Gas Combustion Factor	g CO_2-e/MJ	Uniform(350,370)	0.14
#6	Natural Gas Percent Methane (by volume)	%	Triangular(.83,.93,.95)	0.09
#7	Unconv well completion: total vent/flare	Mt CH_4	Triangular(13.5,177,385)	0.07
#8	well completion: EUR	Bcf	Triangular(0.5,2,5.3)	(0.06)
#9	CO2 vent	g CO_2-e/MJ	Triangular(.2,.7,2.8)	0.06
#10	Flaring	g CO_2-e/MJ	Triangular(0,.43,1.3)	0.05
#11	Shipping Distance	nm	Triangular(181,10514,10514)	0.05
#12	Regasification Emissions	g CO_2-e/MJ	Triangular(0,1,2)	0.04
#13	Conv. Lease plant energy	g CO_2-e/MJ	Triangular(2,3.3,4.3)	0.04
#14	Well completion: flare rate	%	Triangular(.15,.41,1)	0.03
#15	Well pad construction	g CO_2-e/MJ	Triangular(.05,.13,.3)	0.03

9. Life cycle emissions sensitivity analysis

A sensitivity analysis of the parameters and assumptions was conducted for electricity generation via U.S. LNG exports using TopRank (part of the Palisade Decision Tools software suite). The inputs were varied with 20 steps, the values of which are automatically calculated by the program based on the inputted distributions for each variable. The results suggest that the model is most sensitive to the GWP, fugitive emissions rate, and power plant efficiency. The percent change in output based on the change in input parameters is shown in Figure S9. The base value (0%) is 644 g CO_2-equiv/kWh.

Table S17: The parameters identified by the one-way sensitivity analysis in TopRank that change the total life cycle emissions from electricity generation using U.S. LNG by more than 1% from the base case (644 gCO_2-equiv/kWh). Also shown are the parameter distributions, the min value, the max value, and the base value. Note, because TopRank is limited in the types of input distributions, the liquefaction emissions extreme value distribution was refit to a triangular distribution

			Minimum			Maximum			Base Value
			Output		**Input**	**Output**		**Base**	**Input**
Rank	**Input Name**	**Distribution**	**Value**	**Change (%)**	**Value**	**Value**	**Change (%)**	**Value**	
1	CH_4 GWP (100-year)	Normal	608	-5.7%	28	681	5.7%	43.7	36
2	Fugitive Emissions Rate	Triangular	614	-4.7%	2.5	675	4.7%	3.6	3
3	NGCC Power Plant Efficiency	Triangular	627	-2.7%	0.49	664	3.1%	0.43	0.46
4	Liquefaction Emissions	Triangular	629	-2.4%	3.9	657	1.9%	7.4	5.8
5	% Methane (By volume)	Uniform	626	-2.8%	0.8	648	0.56%	1.0	0.9
6	Natural Gas Combustion Factor	Uniform	634	-1.6%	350	654	1.55%	370	360.0
7	Shipping Distance	Triangular	638	-1.0%	4617	649	0.73%	10514	7988

(min=3.9, avg = 5.8, max=7.4).

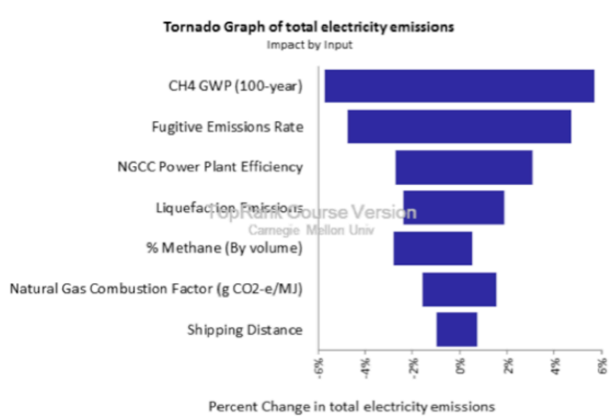


Figure S9: Tornado diagram representing the parameters and assumptions that have the largest impact on the results of the Monte Carlo simulation

10. Natural gas end uses

While the electric power sector accounts for a large portion of natural gas end use, industrial natural gas use generally accounts for a similar portion of natural gas end use. In these data, the industrial sector includes natural gas use for activities including processing and assembly, space conditioning, lighting, and as feedstocks for the production of non-energy products such as plastics and fertilizer. Additional descriptions of the sectors are available in the EIA's International Energy Outlook (2013).[31]

Generally, in table S19 we see that the electric power and the industrial sectors are responsible for an approximately equivalent share of natural gas end use. This is especially true on a regional bases for OECD Europe, globally, and within the U.S. This supports the fact that the GHG emissions from heating should be considered in addition to the GHG emissions derived from natural gas combustion for electricity generation. One exception to the approximate equal share of end use between electric power and industrial sectors is China, where the industrial sector accounts for 46% of the end use while the electric power sector only accounts for 15%. This is partially due to the fact that China produces a large quantity of plastics and chemicals that use natural gas as a feedstock. On the other hand, in Japan and South Korea, the electric power sector's natural gas consumption far outweighs industrial natural gas consumption.

Table S18: Natural gas consumption by sector, total energy consumption, and LNG imports for relevant countries and regions of interest for this study.[29-31]

Country/Region	**Consumption by Sector in 2012 (%)[31]**					**Total Natural Gas Energy Consumption[31]**	**LNG imports[32]**
	Residential	Commercial	Industrial	Transportation	Electric Power Sector	(Quadrillion Btu)	Tcf
China	23.9	6.5	45.7	6.5	15.2	4.6	0.7
India	-	-	52.2	8.7	43.5	2.3	0.7
Japan	7.5	15.1	11.3	-	66.0	5.3	4.2
South Korea	23.5	11.8	17.6	-	47.1	1.7	1.8
OECD Europe	26.9	10.4	31.3	0.5	30.8	20.1	2.3*
U.S.	17.2	11.5	32.4	3.1	32.4	26.2	0.2
World	16.2	6.7	38.5	3.2	35.5	120.4	11.6

* OECD LNG import data obtained from the IEA gas medium-term market report[33]

11. Coal power plant emissions

The assumption that there is no regional variation in average coal fired power plant emissions is derived from a study by Steinmann et al. (2014) that estimated power plant emissions using a regression framework.[30] The results of their analysis for the relevant countries are shown in Figure S10. For reference, the US emissions from coal fired power plants reported by eGRID[34] is shown with a grey dotted line.

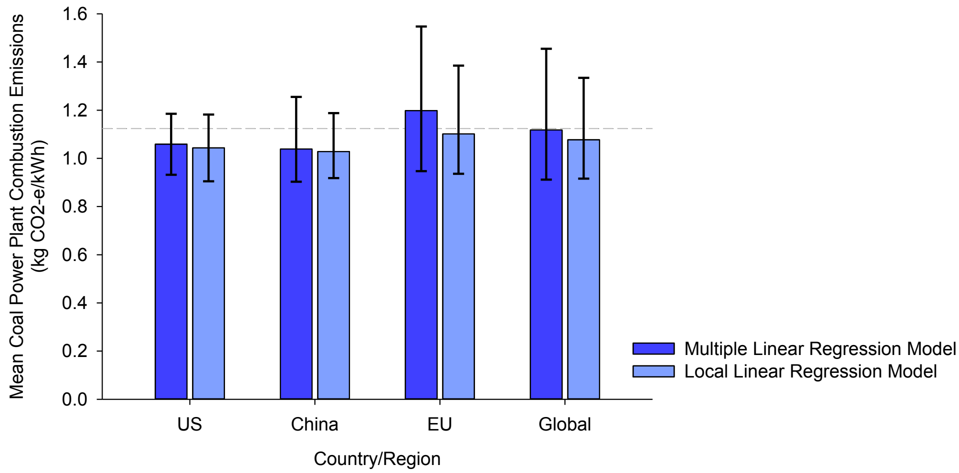


Figure S10: Comparison of coal power plant combustion emissions in the U.S., China, across the EU, and globally as modeled by Steinmann et al. (2014), and compared to EGRID emissions (dotted grey line). A description of the multiple linear regression model and local linear regression model is available in the Steinmann et al. article.

12. The Social Cost of Carbon

The social cost of carbon (SCC) used in this analysis is based on the 2020 value from the US Interagency Working Group's Technical Update (2013).[35] For a 3% discount rate, the average social cost of carbon for a discount rate year of 2020 is $43/metric ton (in 2007 dollars). This was then adjusted to 2014 dollars based on the ratio of consumer price indices. In 2014 dollars, the average SCC at a 3% discount rate is thus $48.97. The minimum and maximum average SCC across different interest rates were $13.80 and $148 per metric ton respectively ($2014).

13. References

1. Weber, C. L.; Clavin, C., Life cycle carbon footprint of shale gas: review of evidence and implications. *Environmental science & technology* **2012,** *46* (11), 5688-95.
2. Schwietzke, S.; Griffin, W. M.; Matthews, H. S.; Bruhwiler, L. M., Natural gas fugitive emissions rates constrained by global atmospheric methane and ethane. *Environmental science & technology* **2014,** *48* (14), 7714-22.
3. Heath, G. A.; O'Donoughue, P.; Arent, D. J.; Bazilian, M., Harmonization of initial estimates of shale gas life cycle greenhouse gas emissions for electric power generation. *Proceedings of the National Academy of Sciences of the United States of America* **2014,** *111* (31), E3167-76.
4. Howarth, R.; Santoro, R.; Ingraffea, A., Methane and the greenhouse-gas foot- print of natural gas from shale formations. *Climate Change* **2011,** *106* (4), 679-690.
5. Jiang, M.; Griffin, W. M.; Hendrickson, C.; Jaramillo, P.; VanBriesen, J.; Venkatesh, A., Life cycle greenhouse gas emissions of Marcellus shale gas. *Environmental Research Letters* **2011,** *6* (3), 034014.
6. Venkatesh, A.; Jaramillo, P.; Griffin, W. M.; Matthews, H. S., Uncertainty in life cycle greenhouse gas emissions from United States natural gas end-uses and its effects on policy. *Environmental science & technology* **2011,** *45* (19), 8182-9.
7. Skone, T.; Littlefield, J.; Eckard, R.; Cooney, G.; Marriott, J. *Role of Alternative Energy Sources: Natural Gas Technology Assessment*; National Energy Technology Laboratory (NETL): 2012.
8. Hultman, N.; Rebois, D.; Scholten, M.; Ramig, C., The greenhouse impact of un-conventional gas for electricity generation. *Environmental Research Letters* **2011,** *6* (4).
9. Burnham, A.; Han, J.; Clark, C. E.; Wang, M.; Dunn, J. B.; Palou-Rivera, I., Life-cycle greenhouse gas emissions of shale gas, natural gas, coal, and petroleum. *Environmental science & technology* **2012,** *46* (2), 619-627.
10. Stephenson, T.; Valle, J.; Riera-Palou, X., Modeling the relative GHG emissions of conventional and shale gas production. *Environmental science & technology* **2011,** *45* (24), 10757–10764.
11. Heath G, M. J., Fisher N *Chapter 1: Life cycle greenhouse gas emissions from Barnett shale gas used to generate electricity: Natural Gas and the Trans- formation of the U.S. Energy Sector: Electricity, eds Logan J, et al. (National Renew- able Energy Laboratory, Golden, CO), NREL/TP-6A50-55538.*; 2012.
12. O'Donoughue, P.; Heath, G.; Dolan, S.; Vorum, M., Life cycle greenhouse gas emissions of electricity generated from conventionally-produced natural gas: Systematic review and harmonization. *Journal of Industrial Ecology* **2014,** *18* (1), 125-144.
13. Laurenzi, I.; Jersey, G., Life cycle greenhouse gas emissions and freshwater consumption of Marcellus shale gas. *Environmental science & technology* **2013,** *47* (9), 4896–4903.
14. Tamura, I.; Tanaka, T.; Kagajo, T.; Kuwabara, S.; Yoshioka, T.; Nagata, T.; Kurahashi, K.; Ishitani, H., Life cycle CO2 analysis fo LNG and city gas. *Applied Energy* **2001**.
15. Hardisty, P. E.; Clark, T. S.; Hynes, R. G., Life Cycle Greenhouse Gas Emissions from Electricity Generation: A Comparative Analysis of Australian Energy Sources. *Energies* **2012,** *5*, 872-897.

16. Arteconi, A.; Brandoni, C.; Evangelista, D.; Polonara, F., Life-cycle greenhouse gas analysis of LNG as a heavy vehicle fuel in Europe. *Applied Energy* **2010,** *87* (6), 2005-2013.
17. Skone, T.; Cooney, G.; Jamieson, M.; Littlefield, J.; Marriott, J. *Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas from the United States*; US Department of Energy; National Energy Technology Laboratory: 2014.
18. Heede, R., LNG Supply Chain Greenhouse Gas Emissions for the Cabrillo Deepwater Port- Natural Gas from Australia to California. **2006**.
19. Verbeek, R.; Kadijk, G.; Van Mensch, P.; Wulffers, C.; Van Den Beemt, B.; Fraga, F. *Environmental and Economic aspects of using LNG as a fuel for shipping in The Netherlands*; TNO: 2011.
20. *LCFS Life Cycle Fuel Pathway Report Method 2B Application: Topock LNG Plant to LNG and L-CNG Applied Natural Gas Fuels, Inc*; Applied Natural Gas Fuels, Inc.
21. Cohen, A. K. *The Shale Gas Paradox- Assessing the Impacts of the Shale Gas Revolution on Electricity Markets and Climate Change*; Harvard Kennedy School: 2013.
22. Biswas, W.; Engelbrecht, D.; Rosano, M. *A life cycle assessment of Western Australian LNG production and export to the Chinese market*; Western Australian Energy Research Alliance (WAERA): 2011.
23. Yoon, S. Y.; Yamada, T., Life-cycle inventory analysis on fossil energy in Japan. *Energy Economics* **1999,** *25* (8), 22-48 [in Japanese].
24. Okamura, T.; Furukawa, M.; Ishitani, H., Future forecast for life-cycle greenhouse gas emissions of LNG and city gas 13A. *Applied Energy* **2007,** *84* (11), 1136-1149.
25. Yost, C.; DiNapoli, R., Benchmarking Study Compares LNG Plant Costs. *Oil & Gas Journal* **2003,** *101* (27).
26. Barnett, P., Life Cycle Assessment (LCA) of Liquefied Natural Gas (LNG) and its environmental impact as a low carbon energy source. **2010**.
27. Port distance calculator. http://www.sea-distances.org/.
28. Corbett, J.; Winebrake, J., Emissions Tradeoffs among Alternative Marine Fuels: Total Fuel Cycle Analysis of Residual Oil, Marine Gas Oil, and Marine Diesel Oil. *Journal of the Air & Waste Management Association* **2008,** *58* (4), 538-542.
29. Venkatesh, A.; Jaramillo, P.; Griffin, W. M.; Matthews, H. S., Uncertainty in life cycle greenhouse gas emissions from United States coal. *Energy & Fuels* **2012,** *26* (8), 4917-4923.
30. Steinmann, Z. J.; Venkatesh, A.; Hauck, M.; Schipper, A. M.; Karuppiah, R.; Laurenzi, I. J.; Huijbregts, M. A., How to address data gaps in life cycle inventories: a case study on estimating CO2 emissions from coal-fired electricity plants on a global scale. *Environmental science & technology* **2014,** *48* (9), 5282-9.
31. EIA *International Energy Outlook 2013*; U.S. Energy Information Administration: 2013.
32. BP *Statistical Review of World Energy*; British Petroleum (BP): U.K., 2013.
33. IEA *Gas Medium-Term Market Report; Market trends and projections to 2018*; International Energy Agency: 2013.
34. eGRID Database. (accessed 10/26/14).
35. *Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis*; Interagency Working Group on Social Cost of Carbon: 2014.